STATE OF CALIFORNIA GRAY DAVIS, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

May 20, 2003 **Agenda ID #2258**

TO: PARTIES OF RECORD IN RULEMAKING 01-10-024

This is the proposed decision of Administrative Law Judge (ALJ) Allen, previously designated as the principal hearing officer in this proceeding. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180 a Ratesetting Deliberative Meeting to consider this matter may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the Ratesetting Deliberative Meeting 10 days before hand, and will advise the parties of this fact, and of the related ex parte communications prohibition period.

The Commission may act at the regular meeting, or it may postpone action until later. If action is postponed, the Commission will announce whether and when there will be a further prohibition on communications.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at http://www.cpuc.ca.gov. Pursuant to Rule 77.3 opening comments shall not exceed 15 pages. Finally, comments must be served separately on the ALJ and the assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail, or other expeditious method of service.

/s/ ANGELA K. MINKIN
Angela K. Minkin, Chief
Administrative Law Judge

ANG:hkr
148083

Decision **PROPOSED DECISION OF ALJ ALLEN** **(Mailed 5/20/2003)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001)

ORDER INITIATING IMPLEMENTATION OF THE SENATE BILL 1078 RENEWABLE PORTFOLIO STANDARD PROGRAM

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ORDER INITIATING IMPLEMENTATION OF THE SENATE BILL 1078 RENEWABLE PORTFOLIO STANDARD PROGRAM

California Senate Bill (SB) 1078 established the California Renewables Portfolio Standard (RPS) Program, with a stated intent of attaining a target of 20 percent renewable energy for the State of California. To reach that goal, the legislation requires an increase in procurement of renewable energy of at least one percent per year. The Legislature found that increasing California's reliance on renewable energy resources may have significant economic, social, health, and environmental benefits. (Pub. Util. Code § 399.11.) SB 1078 requires the Commission to adopt, not later than six months after its effective date: 1) a process for determining the market price of electricity; 2) a process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual obligations of the RPS program; 3) flexible rules for compliance in cases of excess or inadequate annual procurement; and 4) standard contract terms and conditions. (Pub. Util. Code § 399.14(a)(2).) This decision takes these first steps in the process of implementing SB 1078.

Procedural Background

Consistent with SB 1078, the Commission is working collaboratively with the California Energy Commission in this proceeding. (See, Administrative Law Judge's Ruling Issuing Workplan and Collaboration Guidelines, dated February 3, 2003.)

Because of the statutory deadline, this proceeding had a highly expedited schedule, particularly given the complexity of the tasks involved:

February 25, 2003	Workshop: Developing Flexible Compliance Mechanisms
March 4	Workshop: Determining the Market Price Referents
March 11	Workshop: Establishing Standard Contract Terms and Conditions
March 18	Workshop: Defining Least Cost and Best Fit and Bid Ranking Criteria
March 27	Testimony
April 7-16	Evidentiary Hearings
April 28	Concurrent Opening Briefs
May 5	Concurrent Reply Briefs
May 20	Proposed Decision

The Parties

This proceeding had a large number of active participants. Testimony or briefs were submitted by Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), The Utility Reform Network (TURN),[1] the Commission's Office of Ratepayer Advocates (ORA), the Union of Concerned Scientists (UCS), the Green Power Institute (Green Power), the California Independent System Operator (ISO), the Center for Energy Efficiency and Renewable Technologies (CEERT), the California Wind Energy Association (CalWEA), the Alliance for Retail Energy Markets (AReM), the Independent Energy Producers (IEP), the California Biomass Energy Alliance (CBEA), Ridgewood Olinda, LLC (Ridgewood), Solargenix Energy LLC

[1] In an unusual alignment, SDG&E and TURN agreed upon and sponsored testimony on "Joint Principles" in this proceeding.

(Solargenix)[2], Chateau Energy, Inc. (Chateau), and Vulcan Power Company (Vulcan).

We appreciate the active participation of so many parties, for while their presence makes the process somewhat more cumbersome, that burden is more than offset by the resulting richness of the record. A significant number of the parties were involved in the legislative process that ultimately resulted in SB 1078, and accordingly bring welcome experience and expertise to the Commission on the issues presented here.

A number of those same parties, however, disagree as to the meaning and purpose of the legislation, and some appear to be attempting to use this proceeding to re-fight battles previously joined at the legislature. We will not substitute our views for those of the legislature. Regardless of how certain parties may regard SB 1078, it is now the law, and we will follow it as written.

Preliminary Issue: Creditworthiness

Before we proceed to address the four specific issues on which we are to adopt rules, we must consider two preliminary issues that overlay the other issues. The first of those is the statutory prerequisite that a utility be deemed creditworthy. PG&E has raised this issue.

The statutory language is fairly plain on the topic of utility creditworthiness:

> The commission shall not require an electrical corporation to conduct procurement to fulfill the renewables portfolio standard until it is deemed creditworthy by the commission upon it having attained an investment grade rating as determined by at least two major rating agencies. Within 90 days of being deemed

[2] Solargenix was formerly known as Duke Solar.

> creditworthy, an electrical corporation shall conduct solicitations to implement a renewable energy procurement plan. The creditworthiness determination required by this paragraph shall apply only to the requirements established pursuant to this article. The requirements established for an electrical corporation pursuant to Section 454.5 shall be governed by that section. (§ 399.14(a)(1).)

The statute also defines "procure":

> For purposes of this article, "procure" means that a utility may acquire the renewable output of electric generation facilities that it owns or for which it has contracted. Nothing in this article is intended to imply that the purchase of electricity from third parties in a wholesale transaction is the preferred method of fulfilling a retail seller's obligation to comply with this article. (§ 399.14(g).)

PG&E argues that it is not subject to any part of SB 1078 for any purpose until it becomes creditworthy. (See, e.g. PG&E Reply Brief, pp. 10 –11.) The scope of PG&E's argument is far-reaching:

> PG&E is not currently subject to the RPS program and shall have no obligation under the decision in this proceeding until it has attained an investment grade rating as determined by at least two major rating agencies. (*id.* at 11.)

The only authority cited by PG&E in support of its position is part of § 399.14(a)(1):

> The commission shall not require an electrical corporation to conduct procurement to fulfill the renewables portfolio standard until it is deemed creditworthy by the commission upon it having attained an investment grade rating as determined by at least two major rating agencies. (PG&E Reply Brief, p. 10.)

There is, however, a mismatch between this statutory language and PG&E's claim. The statute bars the Commission from requiring a non-creditworthy electrical corporation to conduct procurement. That is all the statute prohibits. PG&E, with no explanation, somehow reads the statute to

mean: "The Commission is obligated to defer application of SB 1078 for all purposes until PG&E attains an investment grade credit rating." (PG&E Opening Brief, p. 10, emphasis added.) PG&E's position is simply inconsistent with and unsupported by the statute. We will not order PG&E to conduct procurement prior to its becoming creditworthy, but PG&E is subject to the requirements of SB 1078, and does have obligations arising from this decision.[3]

The question of the precise scope of those obligations remains open, however, as the statute does not provide additional guidance on this point. There are several options. TURN proffers a variety of ways in which the Commission could compel or encourage PG&E to procure renewable power, based in part on other statutory authorities. (See TURN Opening Brief, pp. 11-15.) While this would be the most consistent with the statute's overall policy goal of increasing procurement of renewable resources, it appears to conflict with the language of the statute. Since the Commission "shall not require an electrical corporation to conduct procurement to fulfill the renewables portfolio standard" until it is creditworthy, we will not require an electrical corporation to conduct that same procurement under a different guise.

Alternatively, the Commission could find that, in the absence of an investment-grade credit rating, no annual procurement target (APT) should be set for a given year.[4] This is a more-plausible subset of PG&E's broader

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[3] SCE, the other non-creditworthy utility, takes a less aggressive position than PG&E, and refers to "PG&E's unique position with respect to its creditworthiness in light of its bankruptcy." (SCE Reply Brief, p. 8.)

[4] The APT is the amount of renewable generation a utility must procure in order to meet the requirement that it increase its procurement by at least one percent of retail sales per year. (See § 399.15(b)(1).) The APT is discussed further under the heading "Flexible Rules for Compliance."

argument (PG&E Reply Brief, p. 12). This alternative can best be examined in relation to our other main choice: an APT that is set each year, regardless of a utility's credit status, but without associated procurement being required. CalWEA advocates this position, arguing that APT obligations are not extinguished by lack of creditworthiness, but are only deferred. (CalWEA Reply Brief, pp. 12-13.) With deferral of APT obligations, the compliance mechanism would need to be adjusted to compensate for the fact that no procurement would be made until the utility was deemed creditworthy.

The "no APT" option is easiest on the utility. Once it became creditworthy, it would then begin to procure renewable generation at a 1% percent per year clip, just like other creditworthy utilities. If the utility had an APT set (and deferred) prior to becoming creditworthy, once it became creditworthy it would be behind, and would have to play catch-up to make up the APT that accrued when it was not creditworthy. This could make procurement more difficult, and could give bargaining leverage to renewable generators at the utility's expense.

However, setting an APT for each utility in each year, regardless of the utility's credit rating, is more consistent with the statute's goal of reaching 20% renewable procurement. In addition, both PG&E and SCE have stated that they expect to be creditworthy very soon. Accordingly, very little catch-up would be necessary, so the burden on the utilities is minimal. In addition, we are only requiring the statutory minimum 1% per year annual procurement.[5] The plain language of the statute, which requires an increase in procurement of renewable energy by <u>at least</u> an additional one percent each year, allows us to require even

[5] The utilities may voluntarily procure more than one percent.

greater quantities. (§ 399.15(b)(1).) The fact that the utilities might have to procure more than 1% for a limited period of time is fully consistent with the statute.

However, just because a utility may have an APT before it becomes creditworthy does not mean that a utility should be penalized (or even considered out of compliance) for not procuring renewable energy prior to becoming creditworthy. The potential bargaining leverage gained by renewable generators is reduced if the utility does not risk penalties or a finding of non-compliance if it does not procure renewable energy. Accordingly, a utility's credit rating shall be taken into consideration under the topic of flexible rules for compliance, which is discussed in more detail below.

Preliminary Issue: Renewable Energy Credits

The second preliminary issue is the appropriate use, if any, of renewable energy credits (RECs).[6]

The potential use of RECs was a contentious issue in this proceeding. CEERT defines a REC as consisting "of all renewable and environmental attributes associated with a specific renewable resource separated from its underlying energy." (Ex. RPS-1, p. I-3) CEERT goes on to state: "A REC is created only when the associated renewable resource generates one unit of electricity. This means that the generator has only as many units of RECs as energy generated to sell and no more. A REC is "retired" once it has served its purpose, whether that purpose is to meet an RPS obligation or to substantiate claims for a "green" power content label." (*Id.*) Ridgewood defines a REC more narrowly, with only those non-energy attributes necessary to comply with the

[6] Also referred to as "green tags."

RPS program being represented by the REC. Fuel use, greenhouse gas, and other environmental attributes would not be included in the REC. (Ex. RPS-8, p. 2.)

Some parties advocated that the Commission should ultimately adopt a REC trading system, where RECs could be bought and sold separately from their associated underlying energy. (See, e.g., Ridgewood, Ex. RPS-8, p. 3.) Under this scenario, a utility could meet its RPS obligation by purchasing RECs from a renewable generator without purchasing the corresponding energy from that same generator, and a generator would be free to sell its RECs to someone other than the buyer of its energy.

ALJ Allen ruled that a REC trading system would not be considered in this phase of this proceeding, and we confirm that ruling here. We understand that a number of parties believe a REC trading system to be highly desirable, but the creation of such a trading system is far beyond the scope of what we must accomplish by the statutory deadline of June 30.

While we will leave open the possibility that a REC trading system may be implemented in the future, we note that creation of such a system raises a number of significant issues that would need to be addressed. Before we consider adoption of a REC trading system, we will need a clear showing that a REC trading system would be consistent with the specific goals of SB 1078, would not create or exacerbate environmental justice problems, and would not dilute the environmental benefits provided by renewable generation. Our recent experience in California with electricity markets has also sensitized us to issues of market manipulation, and we would want to be sure that a REC trading system could not be gamed to the detriment of the residents of California.

In contrast to a REC trading system, there appears to be less controversy, but not total agreement, that a REC-based accounting system provides the best way of ensuring compliance with the requirements of the RPS program.

Supporters of a REC-based system, including CEERT, AReM, SDG&E, and CalWEA, argue that a REC-based system should be adopted.

PG&E, however, argues that the time is not ripe for determining whether to use a REC-based accounting system, and observes that the CEC is the agency responsible for developing a tracking and verification system. (PG&E Reply Brief, p. 30.) SCE notes that a REC-based accounting system is not necessary for this phase of this proceeding, as a system that tracks delivered energy would be adequate. (SCE Opening Brief, p. 15) CalWEA acknowledges that, since all renewable attributes are assumed to be transferred with the energy sold, an accounting system that tracks RECs is essentially the same as a system that tracks energy by MWh. (CalWEA Opening Brief, p. 16.)

Nevertheless, a REC-based system has a number of advantages. First, if the Commission were to ultimately adopt REC trading, the process of doing so would be simplified if a REC accounting system was already in place, as opposed to dismantling some other accounting system and then restarting from scratch. (See, CalWEA Opening Brief, p. 16.) Second, REC-based systems are relatively simple and efficient, particularly when compared to the alternative contract path system. (SDG&E Opening Brief, p.24; CEERT Opening Brief, p. 19.) Finally, a REC-based system appears to be particularly well suited to preventing double counting of attributes, as required by § 399.13(b). (SDG&E Opening Brief, supra; CalWEA Opening Brief, supra.)

While the CEC is ultimately responsible for the design and implementation of the accounting system to be used to verify compliance with the RPS standard (§ 399.13(b)), based on the record before us, it appears that a REC-based accounting system is preferable to a contract-based system. We accordingly recommend to the CEC that they consider using a REC-based accounting system.

In order to implement a REC-based accounting system, a REC must be defined. The utility must know what renewable attributes it is acquiring, primarily to ensure that those acquisitions satisfy the requirements of the RPS program. Similarly, renewable generators need to know exactly what attributes they have sold to the utilities. Finally, the statute requires that renewable energy output is counted only once for RPS purposes. (§ 399.13(b).)

In response to requests from parties for a definition of RECs, ALJ Allen ruled that, for purposes of this phase of this proceeding, a REC incorporates all of the environmental attributes of a particular resource. (Tr. p. 2468.) This ruling was consistent with the positions taken by many parties, including PG&E, CEERT, TURN, and SDG&E.

Subsequently, as a result of issues raised in cross-examination on this issue, and in particular what became known as the "cow manure" hypothetical,[7] ALJ Allen requested parties address the definition of "all" attributes. (Transcript, pp. 3265 and 3539.)

Ridgewood (the proponent of the cow manure hypothetical), argues that attributes associated with generation inputs (such as fuel use) should not be included in the definition of all of the environmental attributes that must be transferred to the utilities under the RPS program. (Ridgewood Opening Brief, p. 3.) According to Ridgewood, generation input or fuel-use attributes include the environmental benefits associated with destroying methane and methane

[7] In the cow manure hypothetical, a developer uses cow manure to generate electricity and receives a payment from a third party developer related to the disposal and/or destruction of the cow manure. (Ridgewood Opening Brief, p. 3, fn. 1.)

producing products produced because a particular fuel is used to generate electricity. (*Id.*)

Among the other parties, TURN appears to have given Ridgewood's arguments the most careful consideration. Ridgewood managed to persuade TURN (albeit with reservations) that the transfer of environmental attributes necessary for RPS program compliance need not include fuel related subsidies, or local subsidies received by the generator for the destruction of particular pre-existing pollutants. (TURN Opening Brief, pp. 32-33.)

Nevertheless, TURN conditioned its agreement with Ridgewood, and would require transfer to the utility of any tradable environmental attributes associated with existing landfill gas QFs under long term contract to the utility, and would also require contracts with new biomass or landfill gas facilities to specify that the net carbon emissions associated with delivered electricity are no greater than zero (so the utility would be credited with the purchase of a zero emission generation source). (*Id.*, p. 32.)

TURN recommends that the Commission adopt the general presumption that all environmental and renewable energy attributes associated with the production of electricity be transferred to the utility and retired in order to verify compliance. (TURN Opening Brief, p. 31.) TURN also recommends that the Commission defer resolution of this issue, with workshops on the issue in the second half of 2003. (*Id.*, p. 33.)

PG&E's position is somewhat similar to TURN's position. PG&E asserts that "all renewable and environmental attributes associated with the generation of electricity are bundled with and conveyed to the purchaser of electricity." (PG&E Reply Brief, p. 30.) PG&E would allow benefits "associated with the renewable developer's remediation of the site" to stay with the developer. (Id.)

PG&E also recommends that a REC system, even if used only for accounting, be addressed in subsequent workshops or in a second phase of this proceeding. (Id.)

While the parties are far from consensus, there is some convergence of positions. We have concerns about unbundling too much of a REC, particularly at this stage. Utilities that procure renewable energy and associated environmental attributes must procure the attributes necessary to satisfy their requirements under the RPS program. A utility that in good faith purchases energy and environmental attributes should not later find out that the developer had sold to some other purchaser the attributes necessary for RPS compliance, leaving the utility in a potentially non-compliant position. Utilities need to know in advance that what they are buying will meet the requirements of the RPS program.

The appropriate starting point for the definition of a REC should be that a REC incorporates all environmental attributes associated with the generation of electricity, and that the REC is transferred to the utility and retired. As a record is developed indicating that specific and well-defined attributes need not or should not be transferred to the utility (such as site remediation or fuel use attributes), such attributes may be separated from the REC that the utility must obtain for purposes of the RPS program. For the time being, we adopt the REC definition and conditions recommended by TURN, as described above. We will examine this issue further, in coordination with the CEC. Parties may also provide comments on the issue of the correct definition of the REC that is transferred to the utility.

Ridgewood also attempts to raise a takings argument by assuming a link between the value of environmental attributes associated with electricity generation and the amount of payment received by a generator from PGC funds. Ridgewood then uses that assumption to argue that if a generator does not

receive PGC funds, it should not have to transfer its environmental attributes to the utility, and if it is required to do so, that transfer amounts to a taking of the generator's environmental attributes. In short, this would be because "[T]he portion of the contract price that was intended to account for the value of Environmental Attributes would not be received," and the generator cannot be required to transfer those attributes to the utilities without just compensation. (Ridgewood Opening Brief, pp. 5-6.)

Ridgewood's argument is based on a false assumption. There is no such rigid correlation between the value of environmental attributes and the level of PGC funding. Generators may bid what they want, and may place whatever value they want on their environmental attributes. Presumably this would go into a generator's calculation of its bid, and its decision whether or not it wants to participate in the RPS program at all.

A generator may bid its energy and environmental attributes at a price below the market price referent, or a generator may bid above the market price referent based solely on its operating costs. It is up to the generator to decide how much its environmental attributes are worth, how much it wants to bid into the RPS program for its energy and environmental attributes, and even if it wants to bid at all. Since the generator gets to decide what it wants to do with its environmental attributes, there is no taking.

Market Price

The first of the statutory tasks before us is to adopt: "A process for determining market prices pursuant to subdivision (c) of Section 399.15" (§ 399.14(a)(2)(A).)[8]

Subdivision (c) of § 399.15 reads:

> (c) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following:
>
> (1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the commission.
>
> (2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
>
> (3) The value of different products including baseload, peaking, and as-available output.

It is left up to the Commission exactly how it should take into consideration each of these factors. Subsection (1) requires the Commission to consider the price of specific contracts.

SCE advocates that the Commission should give significant weight to contracts in establishing a market price. (SCE Opening Brief, p. 25-26.) PG&E

[8] Since the market price established by the Commission under this section is to act as a reference point for the award of PGC funds, the parties generally referred to the price established by this process as a "market price referent."

similarly argues that contracts provide a more accurate picture of market prices. (PG&E Opening Brief, p. 18) [9]

While theoretically such contracts would provide a simple and relatively accurate measure of market price, in practice there needs to be a usable quantity of contracts meeting the statutory requirements, and it is not clear that such contracts presently exist. The record does not indicate that there are contracts sufficient in number or comparability to provide a basis for setting a market price. (See, e.g. UCS Opening Brief, p. 6, citing to testimony of TURN and CEERT; Solargenix Opening Brief, p. 6.) Accordingly, while the Commission will certainly consider any such contracts in determining a market price, we cannot rely significantly upon them at this time.

It is possible that in the future there will be more contracts that meet the statutory requirements, but given the recent history of electricity markets in California, the continued presence of DWR contracts, and the utilities' statements regarding their resource needs, we do not foresee that there will be a significant number of such contracts in the near future. As more contracts meeting the statutory description come into existence, the Commission will increase its reliance on such contracts.

In addition to the statutory requirements, SCE proposes that the Commission, in establishing the market price of electricity, should also consider broker quotes and bids that utilities received but did not accept. (SCE Opening

[9] Vulcan's argument that the Commission should use contracts entered into by the California Department of Water Resources (DWR) (Vulcan Opening Brief, pp. 5-6) is inconsistent with the statute.

Brief, pp. 26-28.)[10] According to SCE, these quotes and bids function equivalently to executed contracts, and provide a valuable source of data.

TURN, CalWEA, and Ridgewood (among others) oppose the use of broker quotes or unaccepted bids in establishing the MPR. (TURN Reply Brief, pp. 10-14; CalWEA Reply Brief, pp. 16-17; Ridgewood Opening Brief, p. 15.) According to TURN, CalWEA, and Ridgewood, the use of quotes or bids is inconsistent with the statutory language, which refers to contracts, meaning executed contracts. In addition, such bids or quotes may not provide accurate information. (Id.) TURN also notes that the use of quotes or bids creates an opportunity for manipulation of the market price referent. We agree that the use of bids and unaccepted quotes is not required by the statute, that they are not equivalent to executed contracts and that they should not be used as a significant basis for setting the market price referent.

As a fallback position, SCE argues that if the Commission decides not to use unaccepted bids and broker quotes to directly determine the market price of electricity, it should still consider such data as a check mechanism, to ensure that the market price that is established is "in the ballpark." (SCE Opening Brief, p. 29.) We will allow this use of bids and quotes as an additional source of information. Bid and quote data shall be provided to the staff for their review, but will be given relatively little weight.

Under subsection (2), the Commission is to determine a price based on the costs associated with new generating facilities. In theory, this price and the price established under subsection (1) should converge, but as SCE and TURN note,

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[10] PG&E also supports the use of "valid bids" in determining establishing the market price referent. (PG&E Opening Brief, p.18.)

the electricity market in California is not in equilibrium, rendering such convergence less likely. (See, SCE Opening Brief, p. 28, citing TURN witness Marcus.)[11]

In examining the specified costs associated with a new generating facility, the Commission can look at a typical hypothetical plant as a proxy. Virtually all parties endorse this process, albeit with variations in what costs and assumptions should be included in the proxy, and what type of plant should be used for the proxy.

In determining an appropriate proxy plant, subsection (2) interacts with subsection (3), which requires us to consider the value of different products, including baseload, peaking, and as-available output. Most parties agree that a combined cycle plant is the appropriate proxy for the value of baseload. (See, e.g., SCE Opening Brief, p. 29; CalWEA Opening Brief, p. 8; ORA Opening Brief, p. 6; SDG&E Opening Brief, pp. 4-5.) We will use a combined cycle plant as the proxy for establishing the benchmark price of the baseload product.

There was also wide, if less universal, agreement regarding the most appropriate proxy for establishing a value for a peaking product. While some parties recommended using a combined cycle plant for this product (e.g., CalWEA), most parties acknowledged that a combustion turbine (CT) provided the most accurate proxy for the peaking product. (See, e.g., CEERT Opening Brief, p. 28; PG&E Opening Brief, p. 19; ORA Opening Brief, p. 10; SDG&E

[11] SCE does expect that the two methods should yield roughly equivalent values, but notes that the Commission can and should use its discretion and expertise in weighing the two approaches. (SCE Opening Brief, pp. 17-20.)

Opening Brief, p. 7.)[12] We will use a CT plant as the proxy for establishing the benchmark price of the peaking product.

Subsection (3) also requires that the Commission consider the value of as-available output. As-available (also referred to as intermittent) is a somewhat different creature than baseload and peaking. While baseload and peaking are relatively firm sources of power, differentiated by the type of load they serve and the times of the day or year they operate, an as-available resource is less firm, and may or may not operate at a particular time of the day or year. Some as-available resources may operate at times that correspond to daily or yearly peaks, while others may not. Accordingly, it is difficult, if not impossible, to use a proxy plant for determining the value of as-available output.

If sufficient and appropriate long-term fixed price contracts (as described in subsection (1)) for as-available products existed, then it would be possible to use those contracts to determine the market price for as-available products. We do not have evidence of contracts that are usable for this purpose. To the extent such contracts become available, we will consider them.

In the meantime, the applicable market price referent for an as-available resource will be either the baseload or peaking referent, depending on which product that resource bids. The actual payment made to an as-available resource should be based on its actual performance, as recommended by TURN (Ex. RPS-25, p. 20) and CalWEA (Ex. RPS-12, Chap. 2, p. 2). The implementation of the payment methodology for as-available resources is discussed further below, in

[12] SCE appears to assume that renewables will only offer a baseload product (Opening Brief, p. 19), and does not propose any proxy for valuing a peaking product.

the sections addressing least cost and best fit and standard contract terms and conditions.

In developing the appropriate costs associated with the relevant proxy plants, a number of parties recommend using the CEC's draft staff report "Comparative Cost of California Central Station Electricity Generation Technologies" as a starting point. (See, e.g., PG&E Reply Brief, p. 36; CEERT, Ex. RPS–1, p. II-6; Solargenix, Reply Brief, p. 12.) While the methodology and/or data used in the CEC report may need some adjustments or modifications, the CEC report provides a reasonable and objective starting point.

Coming up with the specific cost components of the proxy plants will require additional work, as a significant amount of detail remains to be developed. Collaborative Staff will examine the CEC report, consider the adjustments and modifications recommended by the parties in this proceeding, and will issue a report containing the Collaborative Staff's recommendations. Following issuance of that report, Collaborative Staff will conduct workshops to further refine the details of the approach to be used. In the interim, we will provide some guidance on issues that have already arisen.

We note that the CEC report does not include the cost of direct assignment transmission facilities.[13] As the cost of these facilities is a direct cost to both a proxy plant and to participating renewable generators, it should be reflected in the MPR.

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[13] These facilities, also referred to as "gen ties," serve to connect the generation facility to the grid, and for siting purposes are typically considered a component of the generation facility. Direct assignment facilities also receive different FERC ratemaking treatment than network upgrades, which are typically sited by the Commission as a utility transmission facility.

Another issue is the appropriate level of project-specificity and site-specificity in the cost analysis. The more project- and site-specific the analysis, the more accurately the proxy would reflect the project being analyzed. On the other hand, this would result in a potentially infinite number of market price referents, one for each project location and configuration. This would render the market price referent far from transparent, and would also be both cumbersome and contentious, with the assumptions for each project a potential source of litigation.

The statute does not require this level of detail. It calls for the proxy to be based upon new generating facilities. (§ 399.15(c)(2).) The use of the plural "facilities" indicates that more than one facility is to be used for the proxy plant. Accordingly, we are going to use representative statewide numbers for factors such as heat rate and line losses. We will only use location-specific costs when those costs have already been specifically quantified for a particular geographic region, such as the cost of emissions offsets.

One of the more actively litigated issues was whether the cost of gas hedging should be included in the proxy. The statute requires us to consider (among other things), long-term fixed-price fuel costs. (§ 399.15(c)(2).) In the absence of comparable long-term fixed gas supply contracts, hedging is an established and appropriate method of fixing future costs. (TURN Opening Brief, pp. 22-23; UCS Opening Brief, pp. 8-12; ORA Opening Brief, p. 7; SDG&E Opening Brief, p. 6).

SCE argues that if there is a market for actual fixed price fuel contracts with a term equivalent to the term of the RPS contracts, then the Commission should refer to those actual contracts, rather than using a hedge value. (SCE Opening Brief, p. 34.) There is, however, no evidence that such contracts currently exist. If some come into being at some point in the future, the

Commission will consider them at that time. In the meantime, hedging provides a reasonable alternative, and is more consistent with the statute than ignoring the costs associated with obtaining fixed prices for fuel on a long-term basis.

PG&E initially argued that the gas hedging costs of a combined cycle plant are likely to be minimal, and therefore should not be included. (Ex. RPS-7, pp. 3-5.) Several parties, however, cited to a study by Lawrence Berkeley National Laboratory (Ex. RPS-28) that found potentially significant costs for gas hedging. (See, e.g., UCS Opening Brief, p. 10.) Roughly similar costs were presented by Platts Research and Consulting. (See, e.g., Vulcan Opening Brief, pp. 5-6.) Even if PG&E is correct, the mere fact that hedge costs are likely to be small does not mean that they should be excluded from consideration.

SCE and PG&E question the reliability and methodology used in the Lawrence Berkeley and Platts studies. (See, SCE Opening Brief, pp. 34-38.) For example, the Lawrence Berkeley study relied in large part on the now-defunct Enron Online, and was based on data dating from the year 2000. These are reasonable criticisms. Undoubtedly updated information and methodological refinements will be used in future studies, making them more accurate than the current Lawrence Berkeley and Platts studies. We do not adopt a specific hedge value or methodology here, but we direct Collaborative Staff to use the best available methodology and data to calculate a gas hedge value for the relevant proxy plant.

Several parties argue that other items should be added to the proxy plant cost. UCS argues that the proxy should include a component reflecting the cost of possible future environmental regulations. (UCS Opening Brief, pp. 12-13.) For example, UCS states that new environmental regulations, such as those regulating carbon dioxide, are likely to result in an increase in gas prices. (*Id.*, p. 13.) The methodology we adopt today incorporates known and actual costs.

The costs UCS would have us include are too speculative at present. (See, e.g., SCE Reply Brief, pp. 7-8; PG&E Reply Brief, p 37.) We will incorporate them only when they become more definite, both in likelihood and value. Other issues relating to the proxy inputs will be addressed in later phases of this proceeding, subsequent to the Collaborative Staff report and workshops described above.

CalWEA and SCE recommend that the Commission disaggregate its benchmarks into separate energy and capacity components. (CalWEA Opening Brief, pp. 6-7; Ex. RPS-5, pp. 13-14.) TURN, SDG&E and PG&E recommend that energy and capacity components of the market price referent be bundled into a single "all-in" benchmark. (TURN Reply Brief, p. 18.) Both sides argue that their position is both simpler and more accurate, but there are plusses and minuses for each approach. On balance, we find that the separate energy and capacity approach is preferable. We will adopt the CalWEA version, in which the Commission (rather than the utility) calculates the capacity benchmark. As CalWEA points out, the Commission has significant experience in this process. (CalWEA Opening Brief, pp. 8-9.) This issue is discussed further in the section addressing "Least Cost and Best Fit."

On another and more general legal issue, SCE argues that the Commission "cannot direct utilities to enter into contracts that exceed avoided cost as that term is defined under the Public Utilities' Regulatory Policy Act of 1978, 16 U.S.C. section 824a-3 et seq. ("PURPA"), as interpreted by the Federal Energy Regulatory Commission ("FERC")." (SCE Opening Brief, p. 20.)

TURN, CEERT, and CalWEA vociferously dispute SCE's position. TURN argues that SCE blurs the distinction between establishment of a uniform wholesale rate and a competitive bidding process that yields market rates, and that FERC has found PURPA preemption in the former scenario, but has not found PURPA preemption in the latter, nor has FERC found PURPA preemption

in the case of a price limit for renewable resources, even when that limit is set above prevailing market prices. (TURN, Reply Brief p. 22.)

CEERT argues that SB 1078 does not create a wholesale rate for power purchases, but rather sets up a mechanism for determining eligibility for and quantity of PGC fund support. (CEERT Reply Brief, pp. 7-8.)

CalWEA raises similar arguments, namely that the RPS program's market price benchmarks do not establish wholesale rates, and that SCE misconstrues the avoided cost standard. (CalWEA Reply Brief, pp. 22-24.)

SCE does not argue that SB 1078 is in violation of federal law, but only that the Commission's implementation may, if the numbers come out too high, result in federal preemption. Even assuming *arguendo* that SCE is correct in its assertion that the market price referent cannot exceed avoided cost, there is no preemption problem here, as we are not directing SCE to enter into contracts that exceed avoided cost.

According to SCE, the Commission would be in conflict with federal law if it sets the market price referent above the cost of available alternatives and "establishes procurement targets that effectively mandate the utility to execute contracts at prices exceeding the alternatives but within the Commission's benchmark." (SCE Opening Brief, p. 21.) Under SCE's formulation, for preemption issues to arise, two things must happen: the market price referent must be set too high, and the Commission must require SCE to execute contracts at those too-high prices.

SCE overstates the strictness of FERC's preemption standard. The same FERC decision cited by SCE states that FERC gives "great latitude" to state commissions regarding the procedures selected to determine avoided costs. "The Commission [FERC] has not, and does not intend in the future, to second-guess state regulatory authorities' actual determinations of avoided costs (i.e.,

whether the per unit charges are no higher than incremental costs). Rather, the Commission believes its role is limited to ensuring the process used to calculate the per unit charge (i.e., implementation) accords with the statute and our regulations." (*Southern California Edison Company*, 70 FERC ¶61,125 at 61,677 (February 23, 1995).)

SCE is arguing that the Commission may run afoul of federal law if the actual numbers for the market price referent that come out of this process are too high. SCE's argument is inconsistent with FERC's holding on this point. The process for establishing the numbers must accord with federal law, but FERC will not second-guess actual numbers. The process used here for establishing the market price referent is consistent with PURPA, and is also largely consistent with SCE's proposed process.[14]

The second element that SCE states is required for preemption to occur is that the Commission must require SCE to execute contracts above avoided cost. (SCE Opening Brief, p. 21.) SCE argues that the Commission may set procurement targets that "effectively mandate the utility to execute contracts at prices exceeding the alternatives but within the Commission's benchmark." (Id.) SCE does not contend that the Commission is actually going to order it to sign a specific contract at a specific price, as occurred in the cited *Southern California*

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[14] As described above, SCE recommended that 1) the Commission use a combination of comparable contracts and a proxy plant; 2) that a combined cycle plant should be the proxy for the baseload plant; 3) that capacity and energy should be separated, with bids consisting of energy only; and 4) that hedge costs for possible future environmental regulations not be included in the proxy. We adopted all of these recommendations. We did not adopt SCE's recommendations in two areas where SCE provided no evidence in support of its position (i.e., contracts to be given greater weight than proxy plants and use of fixed-price gas contracts rather than hedges).

Edison case. (See also, *Midwest Power Systems, Inc.*, 78 FERC ¶61,067 (January 29, 1997).) Instead, SCE claims that the requirement that SCE increase its procurement of renewable generation may mean that SCE will feel compelled to execute a contract at a too-high price. In essence, SCE is arguing that the Commission would indirectly require SCE to enter a contract at above its avoided cost.

However, the process adopted today pursuant to SB 1078 is far different from the processes at issue before FERC in *Southern California Edison* and *Midwest Power Systems*. Here, SCE gets to issue an RFO for bids from renewable generators, SCE gets to evaluate those bids, SCE gets to negotiate with the bidding generators, SCE gets to decide whether to execute a particular contract, and SCE gets the protection of the flexible compliance mechanism described below. SCE is not required to enter into any specific contract.

ORA recommends that the Commission use the effective load carrying capacity (ELCC) of a renewable technology as a significant part of the market price referent calculation methodology. (ORA Opening Brief, pp. 10-12.) According to ORA, the ELCC more accurately reflects the value of the peaking component of an intermittent resource, which the utilities may undervalue due to intermittent resources' non-dispatchability. Unfortunately, use of the ELCC is necessarily technology-based, which creates a range of issues and problems that are beyond the scope of what we can review in this phase of this proceeding, where our focus is necessarily upon the statutory requirement for a product-based market price referent. Nevertheless, we believe that the ELCC is a useful concept, and we may consider it when adjusting RPS program capacity payments in the future. Parties are encouraged to explore its use in future phases of this proceeding and related proceedings.

Least Cost and Best Fit

The second task before us is to adopt:

> (B) A process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis. This process shall consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources. (§ 399.14(a)(2)(B).)

Least cost and best fit are separate concepts, but pursuant to this statutory direction, we must consider the complex interrelationship between the two for purposes of implementing the RPS program. While least cost can be looked at in a relatively universal manner (once a calculation methodology is standardized), best fit is inextricably linked to the needs of a particular utility.

In that context the utilities should be considering the best fit that is available, which may or may not be a perfect (or even good) fit with their needs. As discussed in more detail below (under the heading "Flexible Rules for Compliance"), compliance with the procurement requirements of the statute is not excused just because a utility believes that the available renewable resources are not an ideal match with its own projected needs. With that caveat, we define best fit as being the renewable resources that best meet the utility's energy, capacity, ancillary service and local reliability needs.

TURN and SDG&E, in their Joint Principles, identify two key concerns. First, the process should seek to balance bid prices with overall portfolio integration costs to ensure the lowest total ratepayer cost, and second, any preference for "best fit" resources should not be used to overly skew the selection process towards high-priced renewables. To the extent that the goals of the RPS program are dependent on PGC funds, procurement of too many high-

priced resources could deplete those funds and frustrate the purpose of SB 1078. (Ex. RPS-25, p. 28.)

At the same time, ORA observes that the criteria we develop should take into consideration the fact that generation procured in the short-term (both renewable and non-renewable) should help contour utility portfolios to meet their load shapes in light of the continuing DWR contracts. Accordingly, for the short-term, renewable generation that can operate as dispatchable or peaker power is higher on the "procurement hierarchy."

According to ORA, however, over time these conditions will change, and in order to meet the goals of the RPS program (and the broader policy goal of diversifying the state's energy portfolio), the procurement hierarchy should be inverted, with increasing amounts of least cost renewable generation added to utilities' portfolios to meet the RPS goals, with new fossil fuel procurement helping to contour the renewable generation to the utilities' load shapes. (Ex. RPS-39, p. 15.)[15] Over time, this should serve to address the ISO's concern regarding the relationship between procurement of new resources and over-generation.

The basic process to be used should be consistent with the general recommendations of CalWEA, that bids must be evaluated on a total cost basis, consistent with the statute, and that each utility should evaluate bids based on a consistent set of economic assumptions. (CalWEA Opening Brief, pp. 11-12.)

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[15] While we may wish to consider this issue further in future years, we do not want short-term procurement of best-fit renewable resources to be made at excessive cost, endangering the existence of longer-term renewable procurement.

Consistent with § 399.14(a), each utility shall, on an annual basis, file a procurement plan stating:

(1) An assessment of its portfolio supply/demand balance to determine the optimal products sought in RPS procurement , including deliverability characteristics;

(2) Anticipated compliance flexibility mechanisms the utility may use, and current status of accrued deficits and surpluses;

(3) A bid solicitation for each product, with online dates and locational preferences; bidders can respond with products of their choosing, but the utility may prefer the products identified in their Commission-approved plan;

(4) Direction to respondent bidders to offer prices for 10, 15, and 20 year contract terms; and

(5) A list of factors the utility will consider as "tiebreakers," that bidders should enumerate and the Procurement Review Group (PRG) should consider when evaluating RPS procurement pursuant to the approved plan.

In light of the legislative direction to conduct RPS planning in conjunction with general procurement planning, we will coordinate with our general procurement proceeding in establishing the schedule for annual RPS plan filings.

The ranking process we adopt is iterative, as recommended by SCE and PG&E:

First Ranking: Bids are ranked according to the product-specific market price referent, adjusted for PGC fund awards:

(1) The price referent reflects the value of two time-differentiated products, baseload and peaking.

(2) Capacity values are set in advance by product, using:

a. Commission-approved capacity values, in $/kW-year, based on a combustion turbine, consistent with the standard

method the Commission has used for Qualifying Facility (QF) capacity, as discussed by ORA and CalWEA.

b. Commission-approved capacity allocation values currently in use for QFs.

(3) Capacity payments are made in two ways:

a. Firm: commitment by generator to supply, with damages for nonperformance.

b. Non-firm/Intermittent: paid for performance.

(4) The CT capacity value will be assessed in the same process in which the Commission establishes the baseload/peaker proxy using CCGT and CT.[16]

a. Capacity allocation values will be updated.

b. The entirety of this capacity payment method is subject to update pending the results of the current CEC Integration analysis.

(5) Bidders submit only an energy price; the capacity price is pre-determined; bids are ranked on energy only, as recommended by CalWEA and SCE.

(6) Consider PGC awards.[17]

Second Ranking: Re-ordered based on integration and transmission costs

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[16] Collaborative Staff, using the CEC study as its starting point, will analyze the accuracy of present CT capacity values, and whether another technology proxy would be more appropriate (e.g., TURN's proposal for using duct firing).

[17] Existing PGC awards should be "stacked" on top of the bid price in the LCBF evaluation to reveal the true, total cost of the bid. For example, in the event two projects are equally priced, but one has a pre-existing PGC award, least cost to ratepayers favors the non-PGC project.

(1) CEC Integration Study working group methods are used to determine total integration costs for each short-listed contract;

a. The results of Phase 1 of the CEC integration study will reveal the integration impacts of present generation in specified areas. These results can act as a proxy for the integration effects of adding new resources in those same areas, if Phase 2 results are not available prior to the first RPS solicitation, as discussed in the TURN/SDG&E Joint Principles.

b. Results of Phase 2 of the CEC Integration Study will provide integration values for future resource additions at specific sites.[18]

c. Intermittent resources utilize the ISO's Amendment 42 and internalize costs into bids; no further utility calculation of schedule deviations is needed, as discussed in the TURN/SDG&E Joint Principles.

d. Remarketing costs are determined using the utilities' own power flow models, which are under consideration in the general procurement proceeding. Results and methods shall be made available to the PRG for review.

(2) Transmission costs will be assessed using the most appropriate process of those available, depending primarily upon whether the project is in the ISO development queue;[19]

a. Direct Assignment facilities are included the MPR, and therefore need to be included in the bid.

b. Network facilities:[20] For bidders already in the ISO Queue, the standard ISO System Integration Study (SIS) and Facility

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[18] We are encouraged by the full participation this CEC process has enjoyed to date.

[19] The below approach assumes the continuation of current FERC ratemaking practice.

[20] CalWEA raises concerns regarding the allocation method (as opposed to the assessment method), which they argue could result in an excessive burden on one bidder, rather than proportionally to all potential bidders in a resource area. This

Footnote continued on next page

Study (FS) will yield sound estimates of network facility costs.[21]

c. Otherwise, for bidders not in the ISO queue with completed cost estimates (i.e. the SIS and FS), PG&E proposes an annual transmission plan that is a workable alternative.[22] PG&E's proposal is a reasonable starting point for the utilities to prepare their plans, although we do modify PG&E's proposal to improve its linkage with our Transmission OII ((I.) 00-11-001).

d. Each proposed developer provides basic interconnection information to the transmission OII, to be defined in that proceeding.

e. Utilities develop a proxy bid price using approved methods, as described in PG&E's Transmission Least Cost and Best Fit Appendix A (Ex. RPS –7).[23]

i. Taking the interconnection information submitted by the bidder into the transmission OII, the utility will prepare an annual cost assessment plan to be made available at least 90 days prior to that year's RPS solicitation.

ii. In the transmission OII, each utility will specify what information it requires of developers to perform this assessment, and the OII will standardize the approach.

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problem is to be addressed in the Commission's OII process, and cannot be decided on the record in this proceeding.

[21] There is general agreement that this is the ideal scenario for determining costs, but it is not always available.

[22] PG&E calls this a "Transmission Ranking Cost Report."

[23] PG&E's proposal is very detailed. While the following steps anticipate addressing it further in the current Transmission OII, parties should feel free to comment on other possible forums for addressing these issues.

The process described above will yield a workable approximation of the costs to the transmission system imposed by each new renewable generator. Several parties expressed concern that requiring an individual generator to finance the entire cost of a network upgrade will create a classic "free rider" problem – every developer will prefer to build the second facility in a new resource area, and take advantage of the investment made by a developer that is willing and able to finance the entire upgrade on their own. In this situation, potentially everyone waits, and no one builds.

While the up-front financing of substantial network facilities may pose a real burden to renewable developers, a true least-cost analysis must consider these costs as being triggered by the addition of particular renewable generators to the grid. At the same time, we recognize that the long-term goals of the RPS program may require a different approach to the financing of new network facilities[24]. We will continue to explore this issue in conjunction with the ongoing Transmission OII.

Regardless of whether an individual generator, all potential generators, or some other entity pays the upfront cost of new network facilities, "least cost" requires that less-expensive generation options be pursued first. Incorporating new network facility costs in the rank-ordering of renewable bids will tend to favor generation with existing transmission facilities available.

In the near term, the likelihood that new renewable generation will require extensive network upgrades is lower than in later years of the RPS program, when the state will need to look farther afield to meet its goals. In later

[24] One example would be to assign transmission costs according to the ratio of a project's MW output to the total potential MW of a particular resource area.

solicitations we hope to have a more articulated method of financing necessary network upgrades, but in the near term the full consideration of network facility costs called for here will yield the most favorable results for ratepayers.

As several parties note, it is conceivable that the addition of renewable generation to the grid may result in network benefits, and bidders are encouraged to describe any such potential benefits in their responses. Similarly, bidders should describe potential benefits of their projects to the considerations of local reliability, low income or minority communities, environmental stewardship, and resource diversity. The utilities should make it known in their annual plans that such benefits are sought, should apply transparent criteria in evaluating such claims, and should present the results of these evaluations to their PRGs for consideration.

Similarly, the utilities may favor curtailability and dispatchability as attributes of bids, but must make their analyses of these benefits clear for PRG and Commission review. As a general principle, we direct the utilities to continue to work cooperatively with their PRGs to develop a common understanding of the basis for evaluation and acceptance of RPS bids.

Flexible Rules for Compliance

The third task before us is to adopt:

> Flexible rules for compliance including, but not limited to, permitting electrical corporations to apply excess procurement in one year to subsequent years or inadequate procurement in one year to not more than the following three years. (Pub. Util. Code § 399.14(a)(2)(C).)

This requirement applies to what is known as the annual procurement target (APT), which is described in § 399.15:

> (b) The commission shall implement annual procurement targets for each electrical corporation as follows:
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> (1) Beginning on January 1, 2003, each electrical corporation shall, pursuant to subdivision (a), increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017. An electrical corporation with 20 percent of retail sales procured from eligible renewable energy resources in any year shall not be required to increase its procurement of such resources in the following year.

When read together, the two sections indicate that the flexible compliance mechanism applies to annual procurement targets only. The language requiring utilities to procure 20 percent of its retail sales <u>no later</u> than December 31, 2017 is clear and unequivocal. The 2017 deadline is absolute. Accordingly, the task before us is to develop flexible rules for compliance applicable to the annual procurement targets.

PG&E raises a threshold issue regarding the basic nature of the APT. According to PG&E, an APT for a given year only exists if the utility identifies, in its general procurement plan, an unmet need for that year. If there is no unmet long term need identified in the utility's general procurement plan for a given year, then there is no incremental APT for that year. (PG&E Opening Brief, pp. 6-7.)[25]

PG&E bases this argument primarily on the language in § 399.15(a) that refers to "unmet long-term resource needs." (See, e.g., Ex. RS-7, pp. 1-4, 1-5, 2-5,

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[25] PG&E's position is disputed by numerous parties, including Vulcan, CalWEA, Chateau, and TURN.

2-6.) PG&E places too much reliance on this phrase, and also interprets it, with scant legal analysis, to be utility-specific and utility-determined.[26]

The section that PG&E relies upon says:

> 399.15. (a) In order to fulfill unmet long-term resource needs, the commission shall establish a renewables portfolio standard requiring all electrical corporations to procure a minimum quantity of output from eligible renewable energy resources as a specified percentage of total kilowatthours sold to their retail end-use customers each calendar year, if sufficient funds are made available pursuant to paragraph (2), and Sections 399.6 and 383.5 to cover the above-market costs of eligible renewables, and subject to all of the following:

This statute imposes an obligation upon the Commission to establish a standard applicable to all electrical corporations. The basis for that broad obligation is "to fulfill unmet long-term resource needs," a term which is not defined in SB 1078. However, the Legislature expressly found and declared that "[I]ncreasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels." And "The development of renewable energy resources may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts." (§ 399.11(b) and (c).)

The Legislature's target of 20 percent renewable energy is also a statewide target, with the purpose of "increasing the diversity, reliability, public health and

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[26] PG&E does make policy-based arguments in support of its interpretation (PG&E Opening Brief, pp. 4, 13-14), but never explains how its position is consistent with the statutory language.

environmental benefits of the energy mix." (§ 399.11(a).) PG&E's position that "unmet long-term resource needs" means a specific utility's resource needs, as defined and identified by that utility, is inconsistent with the statewide focus and purpose of the legislation. "Unmet long-term resource needs" must be considered on a statewide basis, not a utility-by-utility basis, and the legislature has already essentially found that there are statewide unmet long-term resource needs.[27]

Most of PG&E's arguments ultimately boil down to the fact that it considers a mandatory one percent APT to be bad policy. (See, PG&E Opening Brief, pp. 13-14; PG&E Reply Brief, p. 23.) Nevertheless, the statute contains a mandatory one percent APT. While PG&E may believe that to be a bad policy, PG&E's belief does not allow the Commission to ignore the statute's language. In fact, PG&E turns the statutory language on its head when it argues that it should only be required to procure "up to at least 1 percent" of its self-defined need. (PG&E Opening Brief, p. 6.) We decline to do a similar inversion of the plain language of the statute.

Annual procurement targets are not optional. Throughout SB 1078, they are treated as a requirement. (See, e.g., § 399.14(a)(2)(B) referring to annual obligations under the RPS program.) Flexible compliance is only necessary if compliance is required. Since compliance is required under the statute, we now

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[27] If the legislature had intended for the term "unmet resource needs" to relate to a specific utility's needs, it could have easily stated it that way. For example, P.U. Code section 454.5(b)(9)(A), as cited by PG&E, states that procurement shall be done by an electrical corporation "in order to fulfill its unmet resource needs." (PG&E Reply Brief, p. 22.) The word "its" in the statute clearly refers to the electrical corporation. The legislature could have used the same wording for the statute at issue here, but did not do so.

turn to the real issue, which is how to implement the required flexible rules for compliance, as directed by § 399.14(a)(2)(C).

There is significant agreement among the parties that excess renewable procurement in one year should be allowed to be carried over to future years without limitations on time or quantity. (See, e.g. PG&E Opening Brief, p. 9; SDG&E Opening Brief, pp. 19-20; Green Power Opening Brief, p. 2; TURN Opening Brief, p. 34; CalWEA Opening Brief, p. 20.) Such unlimited forward banking is consistent with the language of § 399.14(a)(2)(C), which allows excess procurement in one year to be applied to subsequent years. Furthermore, giving credit for excess procurement is consistent with the purpose of SB 1078. It must be remembered that the 2017 date for 20 percent renewable procurement is a "no later than" date, and the annual procurement requirement of an additional 1 percent of retail sales is an "at least" amount. (§ 399.15(b)(1).) Accordingly, it is fully consistent with the statute for any utility to procure more than 1 percent per year, or to reach 20 percent renewables before 2017.[28]

Furthermore, in the context of SB 1078, unlimited forward banking of excess procurement simply makes sense. As SCE puts it: "Adopting a rule ensuring that all renewable procurement in excess of the current year targets "counts" will effectuate the policy goals of the RPS legislation by creating an incentive for early procurement." (SCE Opening Brief, p. 5) SDG&E also observes that, "It also would smooth out lumpiness in renewables procurement caused by certain renewables projects generating larger than immediately

[28] Under the statute, any utility that reaches the 20% renewable procurement level need not increase its procurement in following years. In conjunction with the "no later than" language, we read this to mean that the 20% obligation continues indefinitely beyond the 2017 deadline.

needed quantities." (SDG&E Opening Brief, pp. 19-20.) Accordingly, we will permit unlimited forward banking of excess procurement.

The main controversy regarding flexible compliance is in the case of inadequate procurement in a given year. In other words, what happens if a utility does not procure enough renewable generation to meet its APT.[29] There are three basic proposals that have been presented, ranging from virtually no flexibility to the absolute maximum flexibility. We adopt a middle ground that blends aspects of the various proposals.

CalWEA proposes the strictest regime. Under CalWEA's proposal, each utility would have three months after the end of a compliance year to remedy any shortfall that existed at the end of that year. (CalWEA Opening Brief, p. 19) For example, if on December 31, 2007, a utility was short of its APT for 2007, it would have until March 31, 2008 to make up the difference. CalWEA's proposal would allow a utility to fall below its APT by 5 percent without penalty and without explanation, but not repeatedly. (Id., p. 20.) CalWEA's proposal is strongly opposed by all three utilities, and garnered no significant support among other parties.

CalWEA's proposal is too rigid, and does not reflect the present realities of renewable procurement. As CalWEA describes the basis for its proposal, its three-month true up mechanism reflects the fact that a utility may be out of compliance "due to naturally occurring variances in annual renewable resource production or variations in load as a result of factors outside the utility's control

[29] "Procure" is defined in § 399.14(g) as being the acquisition of contracted-for output. Accordingly, "procure" as used in this decision refers to actual generation output being available, rather than just the execution of a contract.

(e.g. weather)." (Id. P. 20) The five percent margin reflects the fact that "[I] is impossible to predict precisely how much renewable sellers will generate and how much retail customers will consume." (Id.)

CalWEA's arguments imply a constant supply of renewable generators, with the main variation being in how much energy they generate in a given year. This is not the current reality, nor is it the focus of either the legislation or this proceeding, which in large part is about bringing additional generation units on line - a much lumpier and uncertain process. The five percent margin proposed by CalWEA is simply inadequate to deal with the uncertainties of the real world issues facing the utilities, even if those utilities are committed to procurement of additional renewable resources. Furthermore, it would result in a needless expansion of the Commission's workload in the form of utilities seeking exemption from this requirement.[30]

In addition, the three-month period allowed to make up any deficit is too short. As SCE points out, "CalWEA's true-up proposal essentially collapses the three-year deficit banking provision into three months." (SCE Opening Brief, p.9.) While conceivably the Commission could in fact require the utilities to make up any deficit in three months (as the statute says that the adopted rules should allow "no more than" three years), it is simply not a good idea. As SDG&E argues, the three-month true-up period could create a seller's market (SDG&E Opening Brief, p. 22), which would not be in the best interests of ratepayers.

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[30] CalWEA would only allow carrying over of deficits greater than 5% beyond the three-month true-up period with Commission approval and for specific reasons. (*Id.*, p. 21.)

At the other extreme are the proposals of PG&E and SCE (supported by AReM). They propose adoption of a rule permitting deferral of the entire procurement obligation for up to three years, with no review or penalties. (PG&E Opening Brief, p. 9, SCE Opening Brief, pp. 7-8.)[31] The basically similar proposals of PG&E and SCE correspond to the absolute maximum flexibility permissible under the statute. (See, PG&E Opening Brief, p. 7; SCE Opening Brief, p. 4; Pub. Util. Code § 399.14(a)(2)(C).) While this is something the Commission could adopt, just as we could adopt the CalWEA proposal, it also is not a good idea.

Green Power notes that the SCE and PG&E proposals would allow unlimited deficit carryover for three years, and argues that such deficit carryover could easily be abused and ultimately threaten the goals of the RPS program. (Green Power Opening Brief, p. 2.)

PG&E additionally argues that renewable contracts that expire should not be added to the following year's APT. (PG&E Opening Brief, p. 10.) Instead, the utility would be given the discretion to replace that generation at any time "in order to meet the 20% requirement by 2017." (Id.) SCE takes a similar position. (See, SCE witness Bergmann, Tr. p. 2649.)

TURN responds by arguing that the RPS obligation requires a net increase each year, and that PG&E's position is inconsistent with SB 1078 . (TURN Reply Brief, pp. 4-5.) CalWEA also opposes PG&E's (and SCE's) position, arguing that it could actually result in a year-to-year decline in the total amount of renewable

[31] SCE refers to the 1% obligation as the "entire" obligation. (SCE Opening Brief, p. 7.) This is inconsistent with the statute, which sets 1% as the minimum requirement the Commission can impose, not the maximum.

generation. (CalWEA Reply Brief, pp. 2-3.) Ridgewood also disagrees with PG&E and SCE, arguing that the statutory language clearly mandates a net increase in renewable energy purchases. According to Ridgewood, PG&E and SCE's positions contradict the statute, as they do not require a net increase. (Ridgewood Opening Brief, pp. 8-9.) (See also Green Power, Opening Brief, p.4; Vulcan Opening Brief, pp. 40-41.)

The position of TURN, CalWEA, and Ridgewood is more consistent with the statute than PG&E's and SCE's position. As TURN, CalWEA, and Ridgewood point out, the statute requires each electrical corporation increase its total procurement of eligible renewable energy resources by at least an additional 1 percent of retail sales per year. (TURN Opening Brief, pp. 2-4, CalWEA Reply Brief, pp. 2-4, Ridgewood Opening Brief, pp. 8-9, all citing § 399.15(b)(1).) The focus on the utilities' total procurement indicates that the Commission cannot ignore the expiration of renewable contracts, as those contracts are part of the total.

SCE and PG&E would sever any linkage between the annual targets of 1% and the eventual 20% target. This simply makes no sense; the small annual targets are steps on the way to the larger ultimate target, and eliminating the steps would make the ultimate target that much harder to reach. The criticisms of SCE's and PG&E's proposed flexible compliance rules are accurate: their proposed rules are simply too flexible, and fail to ensure compliance.

TURN and SDG&E have jointly proposed a flexible compliance mechanism. If a utility failed to procure (and did not have banked from previous years) sufficient energy to meet its APT, it would be allowed to carry forward a shortfall of 25% of its APT without Commission approval. (SDG&E Opening Brief, p. 20.) Carrying forward any shortfall larger than 25% would require Commission approval, dependent upon the utility making a showing of specific

conditions. (TURN Opening Brief, p.35.) The TURN/SDG&E proposal is based on the expectation that a utility should be able to obtain at least 75% of its APT in the current year. (SDG&E Opening Brief, p. 20.) Ridgewood, Green Power, and Solargenix support the TURN/SDG&E proposal.

TURN and SDG&E also differ from PG&E and SCE in how a deficit that is carried over is subsequently made up. SCE describes its proposal: "Any compliance in a year following a deficient year should be applied first in fulfillment of the oldest outstanding, unmet compliance targets." (SCE Opening Brief, p. 7) So if in 2010, SCE had an APT of 50 units, but only acquired 40 units, the first 10 units acquired in 2011 would go to make up the deficit. TURN criticizes this feature as allowing the utility "to simply defer procurement for up to three years and carry a three year deficit indefinitely." (TURN Opening Brief, p. 37.) While slightly overstated, TURN's criticism is well founded, as SCE's proposal would allow a utility to essentially roll over its deficit each year.

By contrast, SDG&E would only permit a utility to use renewable MWh in excess of the utility's APT in a given year to make up a prior year's shortfall; in other words, a utility must first apply its procurement to its current year's APT, and only after that is satisfied can any excess procurement be utilized to satisfy a shortfall from a prior year. (SDG&E Opening Brief, p. 23.)

While in general the TURN/SDG&E approach is the best of the methods presented, we believe it may be too early in the RPS program for us to adopt it. First, since we are at the beginning of the RPS process, renewable development and procurement may be both more tentative and lumpier than they will be after more of a track record is established. Second, the creditworthiness issues faced by PG&E and SCE (but not by SDG&E) may affect their procurement ability in the short-term. Third, the electricity market in California is still very much in a state of flux, with many outstanding issues pending resolution.

Accordingly, on an interim basis, we adopt a more flexible compliance program than that proposed by TURN and SDG&E. A utility will be allowed to carry over a deficit of 100% of its APT to the next year without explanation.[32] If a minimum of 50% of that carried-over APT is not satisfied by the second year, an order to show cause (OSC) will be issued. Pursuant to that OSC, the utility would have the burden of proof to show why it failed to comply with its APT, and why its failure was reasonable.[33] Inadequacy of PGC funds would provide a justification for non-compliance. We find that the TURN/SDG&E approach to deficit carryover, which requires the present year's APT to be met before applying procurement to previous years' deficits, is consistent with the language and purpose of the statute, and we adopt it.

The following is an example of how our adopted approach would work. In 2010, a utility has an APT of 10 units, but procures none. In 2011, the same utility has an APT of 10 and procures 10, resulting in a carried-over 2010 deficit of 10. In 2012, the utility has an APT of 10 and procures 12, resulting in a carried-over 2010 deficit of 8. This is larger than 50% of the APT for 2010. The utility must file the motion or application for an OSC by February 1, 2013.

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[32] This should not be read to limit the Commission's authority to respond to complaints or to institute investigations, particularly in situations where improper behavior is alleged.

[33] If a utility has not met the 50% requirement, it shall file a motion in this proceeding or the successor to this proceeding, requesting an OSC hearing, and stating the reasons and justification for its failure to comply with its APT. If no appropriate proceeding is open, the utility shall file an application with the same contents as described for the motion. The utility filing must be made by February 1 of the applicable year. Any interested person or entity may file a motion seeking an OSC on the grounds that the utility is not in compliance with its APT, and has failed to file the appropriate motion or application. The Commission may also issue an OSC on its own motion.

If any APT for a given year remains unsatisfied by the third year, another OSC will issue, following the same procedures and with the same characteristics as already described.

Following a hearing on the OSC, the Commission may impose penalties upon a utility. Every party that addressed penalties acknowledged the Commission's authority to impose penalties under Pub. Util. Code § 399.14(d) and its existing authority. (See, e.g., SCE Opening Brief, pp. 12-13; PG&E Reply Brief, pp. 30-31.) A number of parties, including CalWEA and TURN,[34] recommended the Commission adopt automatic penalties for non-compliance. For the same reasons that we declined to adopt the TURN/SDG&E flexible compliance proposal, we decline to adopt automatic penalties at this time. Should compliance prove to be problematic, we will reconsider this issue.

A utility's compliance with the statute is affected by its creditworthiness. As discussed above, utilities that are not creditworthy are not required to procure under the RPS program. (§ 399.14(a)(1).) Since we determined that a utility will have an APT for a given year even if that utility is not creditworthy, we need to determine how that APT is treated for compliance purposes. We find that just as the APT itself is deferred to future years when the utility is creditworthy, so are the compliance requirements. Compliance requirements are not triggered until the beginning of the first calendar year after the utility is deemed creditworthy by the Commission.

We can use an example of a utility that: 1) in 2004 was not creditworthy and had an APT for 2004 of 10 units; 2) sometime in 2005 became creditworthy and had an APT for 2005 of another 10 units; and 3) had an APT for 2006 of

[34] SDG&E disagreed with TURN on this issue.

another 10 units. In 2006, rather than having a current year requirement of 10 units and a deficit of 20 units, the utility would merely have a current year requirement of 30 units. In other words, the three year compliance period begins when the utility is fully creditworthy in 1996, rather than in 1994, when the APT came into existence.[35]

Overall, the rules we adopt for compliance provide the necessary flexibility not only to deal with the issues of creditworthiness, market uncertainties, and teething pains of the RPS process, but also to satisfy the request of the ISO that our compliance mechanism be flexible enough to reduce the likelihood that utilities may have to deal with excess output at times of expected over-generation conditions. (ISO Opening Brief, p. 9.)

Despite our willingness to provide all utilities more compliance flexibility than recommended by CalWEA, TURN, and SDG&E, we have concerns regarding PG&E's and SCE's apparent resistance to the requirements of SB 1078 and renewable procurement in general. CEERT argues, with some justification, that the intent of PG&E and SCE is to "dismantle, not implement, the RPS Program as intended by SB 1078." (CEERT Reply Brief, p. 2.) PG&E has made very aggressive arguments (especially on the issues of creditworthiness and utility need) in an attempt to remove itself from the requirements of SB 1078. SCE has been slightly less aggressive in its arguments, but SCE's main witness

[35] This process assumes that all utilities subject to this decision become creditworthy, as defined in the statute, no later than three years from the effective date of this decision. If this assumption proves false, the Commission may choose to revisit this issue.

Bergmann (while very knowledgeable and precise) was extremely uncooperative.[36]

We note that the utilities may procure more renewable energy resources than the minimum amount required by the statute and this decision. If PG&E and SCE are serious about proving CEERT wrong, the best way to do that is to voluntarily procure more than the bare legal minimum of renewable generation. This would certainly be the best way to alleviate our concerns, and would also be consistent with California's Energy Action Plan.

Standard Contract Terms and Conditions

The fourth task before us is to adopt:

> (D) Standard terms and conditions to be used by all electrical corporations in contracting for eligible renewable energy resources, including performance requirements for renewable generators. (§ 399.14(a)(2)(D).)

Many active parties recommend that the Commission, in satisfying this requirement, use the Edison Electric Institute (EEI) Master Agreement. Parties differ on what exactly the Commission should do with the EEI contract.

SDG&E argues that the Commission should adopt the EEI contract, but incorporating a limited set of standard terms, including product definitions, contract term, Commission approval language, supplemental energy payment awards and contingencies, ownership of RECs, confidentiality, performance standards, non-performance or termination penalties, scheduling coordination

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[36] While being cross-examined regarding the capacity value of solar facilities, SCE's witness was asked and answered: Q: Does the sun shine at night, Mr. Bergmann? A: Yes, the sun shines all the time. (Tr. p. 2945.)

and responsibility for imbalances. (SDG&E Opening Brief, p.28, citing to TURN/SDG&E Joint Principles.)

PG&E recommends that the Commission adopt the EEI contract, largely as-is, but with the addition of a term defining the renewable attributes that are conveyed. (PG&E Opening Brief, pp. 32-34.)[37] PG&E generally supports the contract development process proposed by SDG&E and TURN. (Id. p. 36.)

IEP proposes using the EEI contract, but with specific modifications. (IEP Reply Brief, p. 1.) CalWEA, while using EEI documentation, seeks greater standardization, arguing that the Commission should standardize as much as possible and adopt actual standard contracts. (CalWEA Opening Brief, p. 24-25.) Vulcan proposes a specific (non-EEI) contract, and also recommends that the Commission adopt "a new SO5 standard contract with price set by resource type," and based at least in part on DWR contract prices. (Vulcan Opening Brief, p. 10.)

CEERT does not specifically endorse the use of the EEI contract, but rather calls for the Commission to encourage further negotiation among the parties and provide direction to the parties on specific issues. (CEERT Opening Brief, p. 31.) CEERT recommends that the terms to be standardized include eligibility, contract term, product definitions, performance requirements, definition and treatment of RECs, credit terms, and prevailing wage, minority and low-income requirements. In addition, CEERT suggests there would be a benefit to standardizing additional terms, including power delivery, termination, contract

[37] PG&E also identifies several general areas where it suggests the Commission "may wish to include" standard terms and conditions. (*Id.*, p. 35.)

modification, assignment, Commission approval, and applicable law. (CEERT Opening Brief, pp. 32-33.)

CEERT's procedural recommendation is sound. As SCE notes, "The Commission does not have before it an adequate record to decide the actual text of the terms to be standardized." (SCE Reply Brief, p. 22.) SCE makes a similar request, that the parties have 90 days to negotiate on a group of standard terms, with the Commission to approve (or otherwise resolve) the results. (*Id.*)

We will not adopt a specific contract here. The statute calls for standard terms and conditions, not a full contract. Accordingly, we will adopt standard terms and conditions, including performance requirements for renewable generators, as required by the statute. At the same time, however, the type and level of detail that is required for fully developing standard terms and conditions is something that falls better within the abilities of the parties to determine, rather than the Commission. Accordingly, we will grant the request of CEERT and SCE for the parties to have the opportunity to negotiate further on the standard terms and conditions to be used.

We believe the proposal of SDG&E and TURN provides the most balanced and considered starting point on this issue. Accordingly, we direct the parties to negotiate more detailed standard terms and conditions, with the SDG&E/TURN proposal as the basis for those negotiations. Parties may ultimately agree to results that differ from the TURN/SDG&E proposal, and should also modify the proposal as necessary to conform to other aspects of this decision that may be inconsistent with the proposal.

TURN argues that the Commission should specifically require prompt negotiation to resolve what it characterizes as a stalemate around repowering of existing wind facilities. (TURN Opening Brief, p. 51.) We endorse this goal, as the repowering of existing wind facilities in prime locations is a common-sense

approach to increasing procurement of renewable energy, with costs that should be lower than for new greenfield projects.

Consistent with the SDG&E/TURN proposal, the utilities should seek bids for 10, 15, and 20-year products. The proposals of SCE and PG&E to seek shorter-term (five-year and one-year) products do not appear likely to promote development of new renewable resources. In addition, § 399.14(a)(4) states that: "In soliciting and procuring eligible renewable energy resources, each electrical corporation shall offer contracts of no less than 10 years in duration, unless the commission approves a contract to shorter duration." We do not see any good reason to permit the utilities to offer contracts of less than 10 years in duration, so we similarly see no reason to deviate from the basic language of the statute.[38]

One area where we depart from the SDG&E/TURN proposal is in the area of bilateral contracts. SDG&E/TURN would allow bilateral contracts, subject to Commission approval. (SDG&E Opening Brief, pp. 48-50.) We prefer to take a slightly narrower approach, and we will allow bilateral contracts only when such contracts are below the market price referent, and do not require any PGC funds.

Confidentiality

Many parties have made arguments relating to the appropriate level of confidentiality of information in the RPS process. We delegate the resolution of this issue to the assigned Administrative Law Judge (or the Law-and-Motion Administrative Law Judge).[39] Among other things, it is possible that any

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[38] The SDG&E/TURN proposal does allow for shorter-term contracts to be bid by developers. Any such shorter-term contracts require express Commission approval.

[39] The ALJ may decide this issue on the present record or may request additional briefing or argument.

determination of the scope of confidentiality may need to be modified as the RPS program implementation proceeds. An ALJ Ruling is more readily adjustable than a Commission decision. At this stage of this proceeding, confidentiality issues are more appropriately addressed by means of a ruling than by decision.

Next Steps

As described in the sections above, there is still significant work to do in the short term in implementing SB 1078, particularly in the areas of the market price referent, standard contract terms and conditions, and confidentiality.

We welcome comments from parties on the best approach to moving forward on these and other issues. We note that SB 1078 calls for a rulemaking on electric service provider participation in the RPS program (§ 399.12(b)(3)(C)), and a rulemaking on community choice aggregator participation in the RPS program (§ 399.12(b)(2)). To meet these statutory requirements, as well as to provide a more focused forum for the issues that require further development from this phase of this proceeding, we will open a new rulemaking.[40]

Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____.

Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Peter V. Allen is the assigned Administrative Law Judge in this proceeding.

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[40] The new rulemaking shall continue to coordinate with the general procurement rulemaking.

Findings of Fact

1. PG&E and SCE are not presently creditworthy for purposes of the RPS program.

2. A renewable energy credit (REC) consists of the renewable and environmental attributes associated with the production of electricity from a renewable resource.

3. As a general matter, renewable energy credits (RECs) can be traded or used as the basis for a renewable energy accounting system.

4. Renewable energy credit (REC) trading is beyond the scope of this phase of this proceeding.

5. In addition to being based on RECs, accounting systems can be based on contracts or units of energy, such as megawatt-hours.

6. For the purposes of this phase of this proceeding, accounting systems based on RECs or units of energy would generally be equivalent.

7. A REC-based accounting system would ease any future adoption of REC trading.

8. The actual design and implementation of an accounting system is the responsibility of the CEC.

9. The market price referent could theoretically best be established by comparison with truly comparable utility procurement contracts.

10. There is no evidence in this proceeding that truly comparable utility procurement contracts presently exist.

11. Broker quotes and unaccepted bids are not equivalent to executed contracts for purposes of establishing the market price referent.

12. The use of proxy generating plants provides an allowable and usable basis for establishing the market price referent.

13. A combined cycle plant is a reasonable proxy for a baseload plant.

14. A combustion turbine is a reasonable proxy for a peaking plant.

15. Plant-based proxies should include appropriate costs, including the cost of transmission facilities and natural gas.

16. There is no evidence in this proceeding that truly comparable long-term fixed price gas supply contracts presently exist.

17. Gas hedge costs are a reasonable proxy for long-term natural gas supply contracts.

18. Completion and use of the plant-based proxies requires further development.

19. The CEC draft staff report "Comparative Cost of California Central Station Electricity Generation Technologies" provides a reasonable starting point for development of the plant-based proxies.

20. Separation of the market price referent into energy and capacity allows bids to be based on an energy-only basis.

21. SCE argues that a too-high market price referent could be inconsistent with federal law.

22. The "best fit" renewable resource does not have to be a perfect fit.

23. "Best fit" criteria should not skew procurement toward high-priced resources.

24. Bids should be assessed on consistent assumptions.

25. Lowest total ratepayer costs should be achieved by balancing bid prices and integration costs.

26. Bids can best be ranked via an iterative process that considers the product-specific market price referent, adjusted for PGC fund awards, and then re-ordered based on integration and transmission costs.

27. The Commission has experience establishing capacity values.

28. Capacity payments should be based on performance.

29. Projects differ in the accuracy of the transmission cost estimates that are available.

30. The ISO's Amendment 42 provides a method for valuing the system costs of intermittent resources.

31. The results of the CEC's Integration Study can serve as a proxy for the addition of new renewable generation in a given resource area.

32. Transmission costs attributable to a new renewable generator should be incorporated into the bid price or assessed independently.

33. The ISO System Integration Study and Facility Study provide the best assessments of network facility costs for new projects.

34. Network benefits should be identified by bidders and evaluated by the utility and the procurement review group.

35. Utility consideration of dispatchability and curtailment in evaluating bids should be transparent and reported to the Commission and the Procurement Review Group.

36. Benefits to low-income and minority communities should be identified by bidders and considered in the bid evaluation process.

37. The annual procurement targets are steps to reaching the goal of 20% renewable resource procurement.

38. Excess procurement in one year may be carried over to future years.

39. Inadequate procurement in one year may be carried over for not more than the following three years.

40. In the case of inadequate procurement in a previous year, the current year's procurement could be applied first to make up the deficit or applied first to the current year's procurement.

41. The newness of the RPS program, the creditworthiness issues faced by PG&E and SCE, and the state of the electricity markets in California, all contribute to uncertainty.

42. The Commission may impose penalties upon utilities for inadequate procurement.

43. The Edison Electric Institute contract provides a reasonable starting point for development of standard contract terms and conditions.

44. The Edison Electric Institute contract requires modification in order to be appropriate for the RPS program.

45. The parties are in a better position than the Commission to evaluate specific terms and conditions.

46. Bilateral contracts would be entered between a utility and a generator outside of the regular bidding process.

47. Confidentiality issues should be addressed by the assigned Administrative Law Judge or the Law-and-Motion Administrative Law Judge.

Conclusions of Law

1. PG&E and SCE are not required to procure renewable energy under the RPS program until they meet the statutory definition of creditworthiness.

2. PG&E and SCE may voluntarily procure renewable energy under the RPS program prior to meeting the statutory definition of creditworthiness.

3. Procurement is the only statutory requirement that is excused by a lack of creditworthiness.

4. Renewable energy credit (REC) trading is not adopted in this phase of this proceeding.

5. We recommend adoption of a REC-based accounting system.

6. Adoption of a REC-based accounting system requires a consistent definition of a REC.

7. The default definition of a REC should include all renewable and environmental attributes associated with production of electricity from a renewable resource.

8. Attributes should only be excluded from inclusion in a REC upon an adequate showing.

9. Parties should have a further opportunity to make a showing why certain attributes should be excluded from inclusion in a REC.

10. TURN's description of the contents of a REC is a reasonable interim approach.

11. The process adopted for use of proxy plants to establish the market price referent is consistent with the statutory requirements.

12. The process adopted for establishing market price referents is not inconsistent with federal law.

13. The process adopted for the ranking of bids is consistent with the statutory requirements.

14. Renewable procurement should be guided by annual Commission-approved renewable procurement plans for each utility, coordinated with the Commission's general procurement rulemaking.

15. The Commission will establish capacity values.

16. Bidders will submit only an energy price, not a capacity price.

17. Network facility costs can be assessed and used to rank bids independently of the determination of cost allocation.

18. Annual procurement targets are required, not optional.

19. The legislature has found that there are statewide unmet long-term resource needs.

20. One percent is the minimum annual procurement increase required by statute.

21. Twenty percent of retail sales are to be procured from eligible renewable resources no later than December 31, 2017.

22. The obligation to procure twenty percent of retail sales from eligible renewable resources extends indefinitely beyond 2017.

23. Inadequate procurement in one year is to be made up in no later than the following three years.

24. Procurement in any year should be applied first to that year's annual procurement target, with any excess procurement then being used to make up a prior year's deficit, or banked for future use.

25. The rules adopted for compliance are flexible and are consistent with the statutory requirements and the Commission's general authority.

26. Parties should have further opportunity to develop standard terms and conditions.

27. Bilateral contracts should only be allowed if they do not require any PGC funds.

28. The process adopted for the development of standard contract terms and conditions is consistent with the statutory requirements.

O R D E R

IT IS ORDERED that:

1. Annual procurement targets shall be set for each utility each year.

2. Compliance with the annual procurement target is not required until a utility is creditworthy.

3. We recommend the adoption of an accounting mechanism based upon renewable energy credits.

4. For purposes of this phase of this proceeding, we adopt TURN's definition of a renewable energy credit, as described above.

5. Parties will have further opportunities to address the definition of a renewable energy credit.

6. We adopt a proxy plant methodology for calculating the market price referent, using a combined cycle proxy plant for the baseload product and a combustion turbine proxy plant for the peaking product, as described above.

7. Parties will have further opportunities to address the components of the proxy plant methodology.

8. The Commission will consider using actual contracts for calculating the market price referent as such contracts are available and appropriate.

9. The Commission may use unaccepted bids and broker quotes only as a check mechanism.

10. The market price referent will be separated into energy and capacity components.

11. The Commission will calculate the capacity component.

12. Bidders will bid only the energy component.

13. Bids will be evaluated on a total cost basis and on a consistent set of economic assumptions.

14. Each utility shall file a renewable procurement plan, as described above.

15. The bidding process shall be iterative, considering first the product-specific market price referent, adjusted for PGC fund awards, and then re-ordered based on integration and transmission costs, as described above.

16. The system costs of intermittent resources shall be valued by use of the ISO's Amendment 42.

17. Transmission costs and benefits of new generation facilities must be considered, as described above.

18. The annual procurement target for each utility is set at one percent per year, as described above.

19. Utilities are allowed unlimited forward banking of excess procurement.

20. Procurement in any year shall be applied first to that year's annual procurement target, with any excess procurement then being used to make up a prior year's deficit, or banked for future use, as described above.

21. Utilities are allowed to carry over a deficit of 100% to the next year, and 50% to a second year without explanation, as described above.

22. Subject to the flexible compliance mechanism, failure to satisfy the annual procurement targets will result in an order to show cause why the utility should not be penalized, as described above.

23. Failure to meet the 20% renewable procurement obligation by the end of 2017 will result in an order to show cause why the utility should not be penalized.

24. The utility obligation to procure 20% of its energy from renewable resources continues beyond 2017.

25. The Edison Electric Institute contract is the starting point for the development of standard contract terms and conditions.

26. Parties will have further opportunities to address standard contract terms and conditions.

27. Bilateral contracts are only allowed if they do not require any PGC funds.

28. Confidentiality issues are referred to the appropriate Administrative Law Judge for resolution via Ruling.

This order is effective today.

Dated _____, at San Francisco, California.